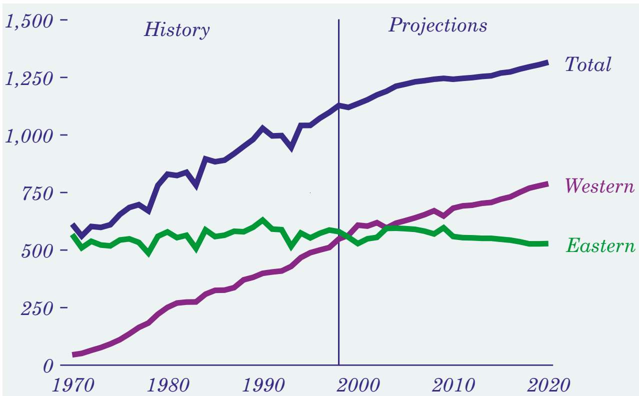
Emissions Caps Lead to More Use of Low-Sulfur Coal From Western Mines

Figure 109. Coal production by region, 1970-2020 (million short tons)



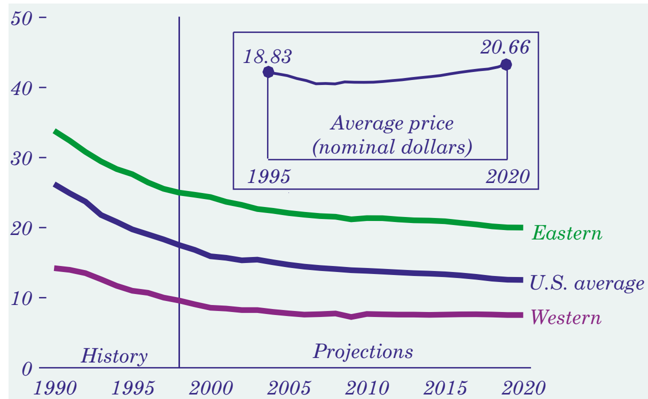
Continued improvements in mine productivity (averaging 6.7 percent a year since 1978) are projected to cause falling real minemouth prices throughout the forecast. Higher electricity demand and lower prices, in turn, yield increasing coal demand, but the demand is subject to a fixed sulfur emissions cap from CAAA90, which mandates progressively greater reliance on the lowest sulfur coals (from Wyoming, Montana, Colorado, and Utah).

The use of western coals can result in up to 85 percent lower sulfur emissions than the use of many types of higher sulfur eastern coal. As coal demand grows, however, new coal-fired generating capacity is required to use the best available control technology: scrubbers or advanced coal technologies that can reduce sulfur emissions by 90 percent or more. Thus, even as the demand for low-sulfur coal grows, there will still be a market for low-cost higher sulfur coal throughout the forecast.

From 1998 to 2020, high- and medium-sulfur coal production declines from 636 to 533 million tons (0.8 percent a year), and low-sulfur coal production rises from 492 to 783 million tons (2.1 percent a year). As a result of the competition between low-sulfur coal and post-combustion sulfur removal, western coal production continues its historic growth, reaching 788 million tons in 2020 (Figure 109), but its annual growth rate falls from the 9.3 percent achieved between 1970 and 1998 to 1.7 percent in the forecast period.

Minemouth Coal Prices Continue To Fall in the Projections

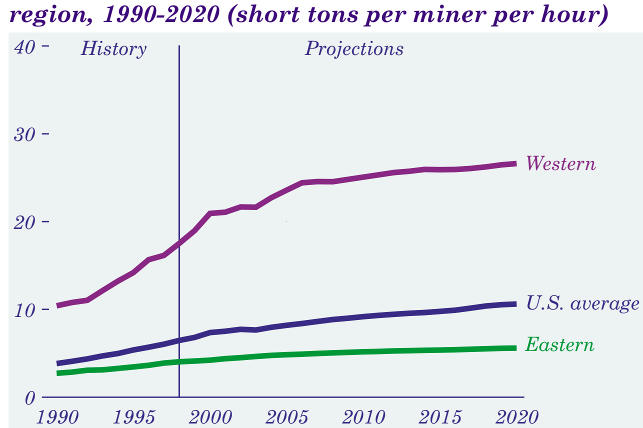
Figure 110. Average minemouth price of coal by region, 1990-2020 (1998 dollars per short ton)



Minemouth coal prices declined by $5.90 per ton in 1998 dollars between 1970 and 1998, and they are projected to decline by 1.5 percent a year, or $4.97 per ton, between 1998 and 2020 (Figure 110). The price of coal delivered to electricity generators, which declined by approximately 70 cents per ton between 1970 and 1998, falls to $20.01 per ton in 2020—a 1.1-percent annual decline.

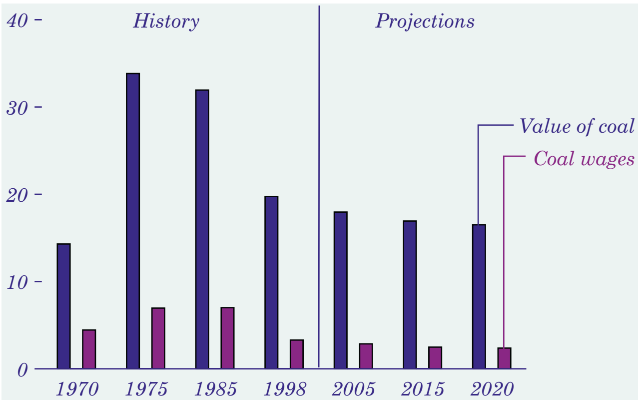
The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is maintained throughout the forecast. Average U.S. labor productivity (Figure 111) follows the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 111. Coal mining labor productivity by region, 1990-2020 (short tons per miner per hour)



Labor Cost Contribution to Total Coal Prices Continues To Decline

Figure 112. Labor cost component of minemouth coal prices, 1970-2020 (billion 1998 dollars)



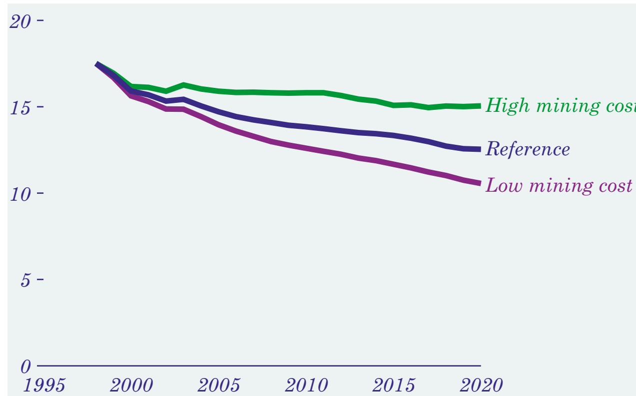
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity will also be influenced by changing regional production shares. Competition from very low sulfur, low-cost western and imported coals is projected to limit the growth of eastern low-sulfur coal mining. The boiler performance of western low-sulfur coal has been successfully tested in all U.S. Census divisions except New England and the Mid-Atlantic, and its penetration of eastern markets is projected to increase.

Eastern coalfields contain extensive reserves of higher sulfur coal in moderately thick seams suited to longwall mining. Maturing technologies for extracting and hauling large volumes of coal in both surface and underground mining suggest that further reductions in mining cost are likely. Improvements in labor productivity have been, and are expected to remain, the key to lower coal mining costs.

As labor productivity improved between 1970 and 1998, the average number of miners working daily fell by 2.2 percent a year. With improvements continuing through 2020, a further decline of 1.5 percent a year in the number of miners is projected. The share of wages in minemouth coal prices [*72*], which fell from 31 percent to 17 percent between 1970 and 1998, is projected to decline to 14 percent by 2020 (Figure 112).

High Labor Cost Assumption Leads to Lower Production in the East

Figure 113. Average minemouth coal prices in three cases, 1998-2020 (1998 dollars per short ton)

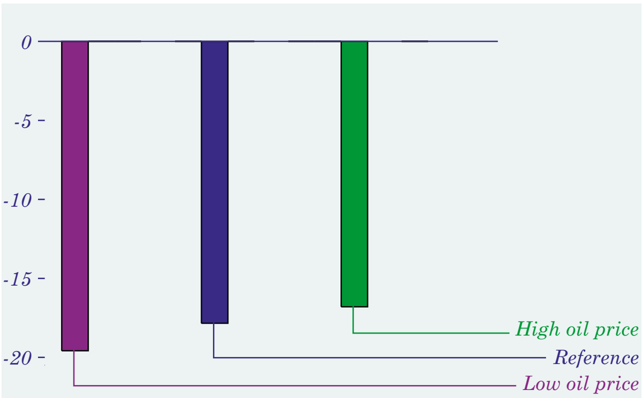


Alternative assumptions about future regional mining costs affect the market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, demand for coal by electricity generators was allowed to respond to relative fuel prices, but coal demand from other sectors was held constant. Minemouth prices, delivered prices, and the resulting regional coal production levels varied with changes in mining costs.

In the reference case projections, productivity increases by 2.3 percent a year through 2020, while wage rates are constant in 1998 dollars. The national minemouth coal price declines by 1.5 percent a year to $12.54 per ton in 2020 (Figure 113). In the low mining cost case, productivity increases by 3.6 percent a year, and real wages decline by 0.5 percent a year [*73*]. The average minemouth price falls by 2.3 percent a year to $10.56 per ton in 2020 (15.8 percent less than in the reference case). Eastern coal production is 57 million tons higher in the low case than in the reference case in 2020, reflecting the higher labor intensity of mining in eastern coalfields. In the high mining cost case, productivity increases by only 0.9 percent a year, and real wages increase by 0.5 percent a year. The average minemouth price of coal falls by 0.7 percent a year to $15.05 per ton in 2020 (20.0 percent higher than in the reference case). Eastern production in 2020 is 14 million tons lower in the high mining cost case than in the reference case.

Transportation Costs Are a Key Factor for Coal Markets

Figure 114. Percent change in coal transportation costs in three cases, 1998-2020

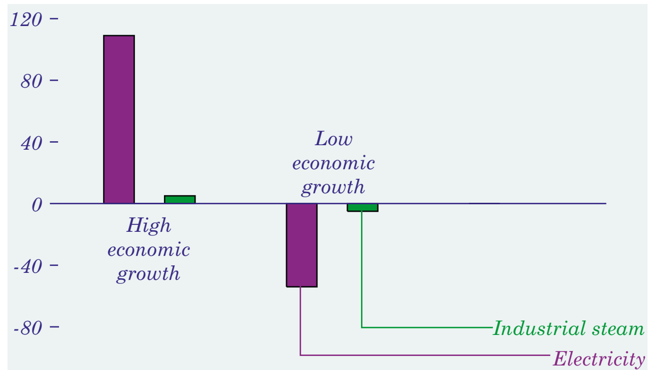


The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation rates (Figure 114), but fuel efficiency also grows with other productivity improvements in the forecast. As a result, in the reference case, average coal transportation rates decline by 0.9 percent a year between 1998 and 2020. The most rapid declines have occurred on routes that originate in coalfields with the greatest declines in real minemouth prices. Railroads are likely to reinvest profits from increasing coal traffic to reduce transportation costs and, thus, expand the market for such coal. Therefore, coalfields that are most successful at improving productivity and lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Expansion of the national market for Powder River Basin coal slowed during 1996 and 1997 as a result of rail service problems after the Union Pacific-Southern Pacific railroad merger. Conditions have since improved, and, assuming that mines in the Powder River Basin complete needed expansion of their train-loading capacities, western coal should be able to meet the increase in demand expected with the advent of Phase 2 of CAAA90. The transition will require more low-sulfur coal than in *AEO99*, because scrubber retrofits are made at a slower pace in *AEO2000*. Any coal transportation problems associated with the increased shift to low-sulfur coal are expected to be temporary.

Higher Oil Prices Would Favor Coal Use for Electricity Generation

Figure 115. Variation from reference case projection of coal demand in two alternative cases, 2020 (million short tons)

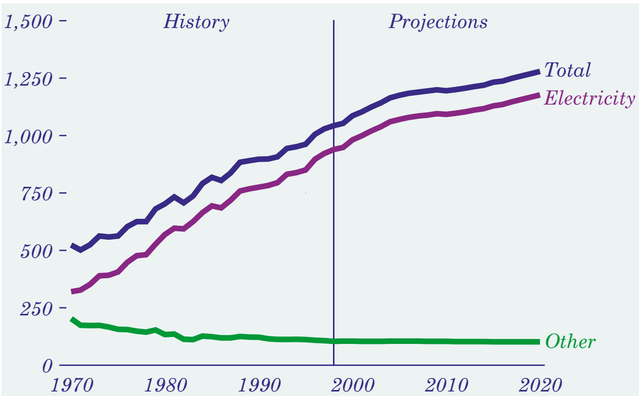


A strong correlation between economic growth and electricity use accounts for the variation in coal demand across the economic growth cases (Figure 115), with domestic coal consumption in 2020 ranging from 1,219 to 1,393 million tons. Of the difference, coal use for electricity generation makes up 163 million tons. The difference in total coal production between the two economic growth cases is 173 million tons, of which 111 million tons (64 percent) is projected to be western production. Despite the fact that western coal must travel up to 2,000 miles to reach some of its markets, when its transportation costs are added to its low mine price and low sulfur allowance cost, it remains competitively priced in all regions except the Northeast.

Changes in world oil prices affect the costs of energy (both diesel fuel and electricity) for coal mining. In the high and low oil price cases, average minemouth coal prices are essentially unchanged and 1.3 percent lower, respectively, in 2020 as compared with the reference case. The low world oil price case projects 24 million tons less coal use in 2020 than the high world oil price case. Low oil prices encourage electricity generation from oil, whereas high oil prices encourage coal consumption. The higher coal consumption in the high oil price case is attributable to the electricity generation sector, with electricity taking 26 million tons of the increase and consumption in the industrial sector declining slightly.

Coal Consumption for Electricity Continues To Rise in the Forecast

Figure 116. Electricity and other coal consumption, 1970-2020 (million short tons)



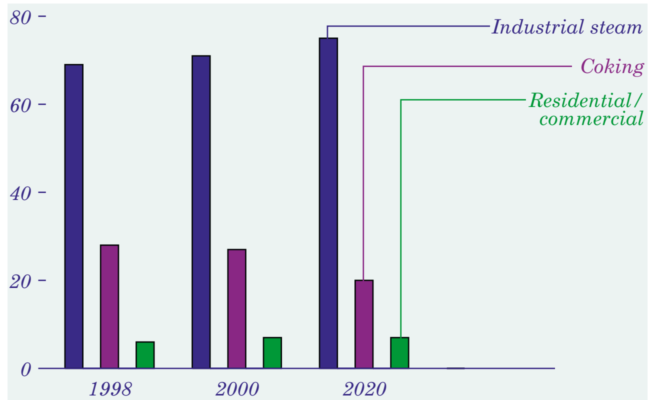
Domestic coal demand rises by 236 million tons in the forecast, from 1,043 million tons in 1998 to 1,279 million tons in 2020 (Figure 116), because of growth in coal use for electricity generation. Coal demand in other domestic end-use sectors declines, as reduced coking coal consumption is partially offset by increased coal demand for industrial cogeneration.

Coal consumption for electricity generation (excluding industrial cogeneration) rises from 939 million tons in 1998 to 1,177 million tons in 2020, due to increased utilization of existing generation capacity and, in later years, additions of new capacity. The average utilization rate for coal-fired power plants increases from 68 percent to 83 percent between 1998 and 2020. Coal consumption (in tons) per kilowatthour of generation is higher for subbituminous and lignite coals than for bituminous coal. Thus, the shift to western coal increases the tonnage per kilowatthour of generation in the midwestern and southeastern regions. In the East, generators shift from higher to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per ton.

Although coal maintains its fuel cost advantage over both oil and natural gas, gas-fired generation is the most economical choice for construction of new power generation units through 2010 when capital, operating, and fuel costs are considered. Between 2010 and 2020, rising natural gas costs and nuclear retirements are projected to cause increasing demand for coal-fired baseload capacity.

Industrial Steam Coal Use Rises, But Demand for Coking Coal Declines

Figure 117. Non-electricity coal consumption by sector, 1998, 2000, and 2020 (million short tons)



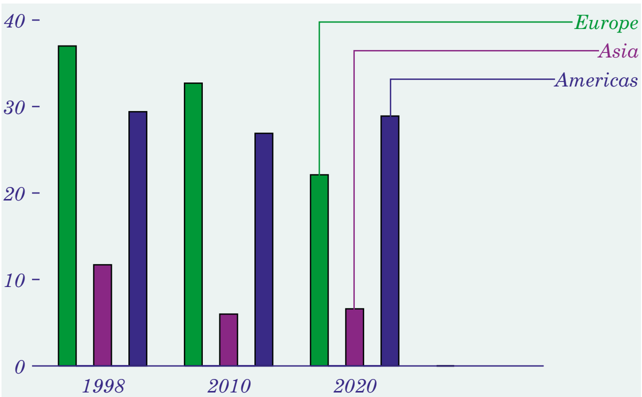
In the non-electricity sectors, an increase of 6 million tons in industrial steam coal consumption between 1998 and 2020 (0.4-percent annual growth) is offset by a decrease of 8 million tons in coking coal consumption (Figure 117). Increasing consumption of industrial steam coal results primarily from greater use of existing coal-fired boilers in energy-intensive industries.

The projected decline in domestic consumption of coking coal results from the displacement of raw steel production from integrated steel mills (which use coal coke for energy and as a material input) by increased production from minimills (which use electric arc furnaces that require no coal coke) and by increased imports of semi-finished steels. The amount of coke required per ton of pig iron produced is also declining, as process efficiency improves and injection of pulverized steam coal is used increasingly in blast furnaces. Domestic consumption of coking coal is projected to fall by 1.6 percent a year through 2020. Domestic production of coking coal is stabilized, in part, by sustained levels of export demand.

Although total energy consumption in the combined residential and commercial sectors grows by 0.9 percent a year, most of the growth is captured by electricity and natural gas. Coal consumption in the residential and commercial sectors remains constant, accounting for less than 1 percent of total U.S. coal demand.

U.S. Coal Exports to Europe and Asia Are Projected To Fall Sharply

Figure 118. U.S. coal exports by destination, 1998, 2010, and 2020 (million short tons)



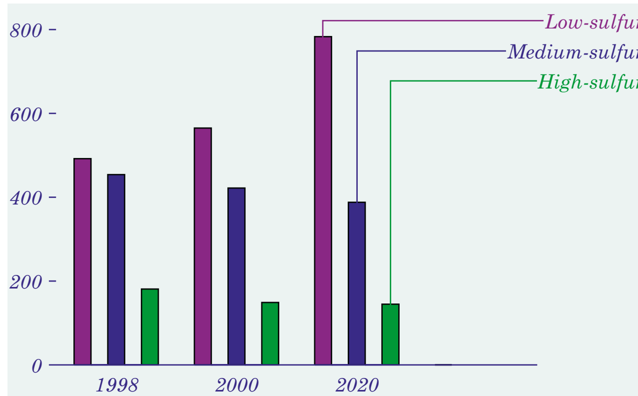
U.S. coal exports show a sharp decline between 1998 and 1999, falling from 78 million tons to 63 million tons, but are projected to remain relatively stable over the forecast horizon, settling at 58 million tons by 2020 (Figure 118). Australian and South African coal export prices dropped substantially in 1999, displacing U.S. coal exports to Europe and Asia. Price cuts by Australia, the world's leading coal exporter, were attributed to both strong productivity growth and a favorable exchange rate against the U.S. dollar.

Between 1999 and 2010, U.S. steam coal exports are projected to increase slightly, from 26 million tons to 29 million tons, as a result of increased coal imports by Europe, reflecting reduced subsidies for domestic coal production and some new generating capacity. During the same period, U.S. coking coal exports are projected to remain virtually unchanged. After 2010, however, both U.S. steam and coking coal exports decline slightly, as Europe shifts away from coal-fired generation and Australian coking coal becomes increasingly competitive, capturing a growing share of the world market.

Faced with strong competition from other coal-exporting countries and limited or negative growth in import demand in Europe and the Americas, the United States captures a decreasing share of both the world and regional coal markets. The U.S. share of total world coal trade is projected to decline from 14 percent in 1998 to 8 percent by 2020.

Low-Sulfur Coal Continues To Gain Share in the Generation Market

Figure 119. Coal production by sulfur content, 1998, 2000, and 2020 (million short tons)



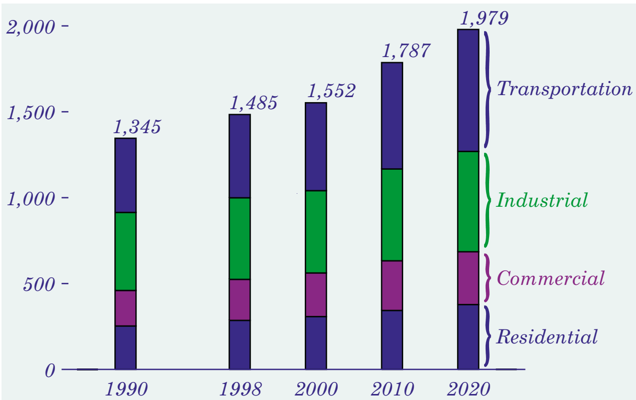
Phase 1 of CAAA90 required 261 coal-fired generating units to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which begins in 2000, tightens the annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller, cleaner plants fired with coal, oil, and gas. The program affects existing utility units serving generators over 25 megawatts capacity and all new utility units [*74*].

Relatively modest capital investments have allowed many generators to blend very low sulfur subbituminous and bituminous coal in Phase 1 affected boilers. Such fuel switching often generates sulfur dioxide allowances beyond those needed for Phase 1 compliance. Excess allowances are banked for use in Phase 2 or sold to other generators (the proceeds of such sales can be seen as further reducing fuel costs for the seller). Fuel switching for regulatory compliance and cost savings is projected to reduce the composite sulfur content of all coal produced (Figure 119). Sulfur emissions from Phase 1 units were 24 percent (1.7 million tons) below the legally allowable limit in 1998 [*75*].

Coal users may incur additional costs in the future if environmental problems associated with nitrogen oxides, particulate emissions, and possibly carbon dioxide emissions from coal combustion are monetized and added to the costs of coal combustion.

Higher Energy Consumption Forecast Increases Carbon Emissions

Figure 120. Carbon emissions by sector, 1990-2020 (million metric tons)



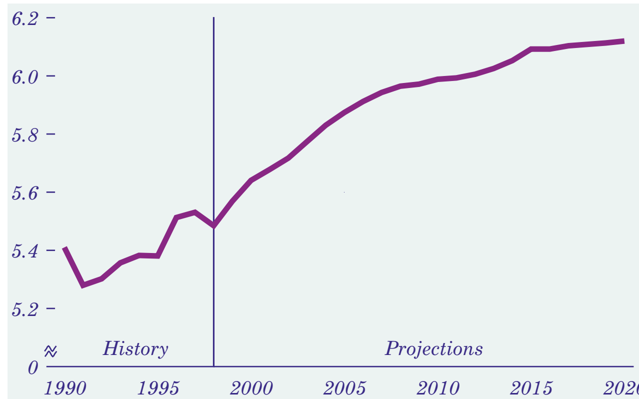
Carbon emissions from energy use are projected to increase by an average of 1.3 percent a year from 1998 to 2020, reaching 1,979 million metric tons (Figure 120). This projection is essentially the same as the *AEO99* projection of 1,975 million metric tons. In *AEO2000*, slightly higher energy consumption resulting from more rapid economic growth, more travel, and more fuel consumption for electricity generation is offset by more optimistic projections for nuclear generation and improvements in energy efficiency.

Increasing concentrations of carbon dioxide, methane, nitrous oxide, and other greenhouse gases may increase the Earth's temperature and affect the climate. The *AEO2000* projections include analysis of the Climate Change Action Plan (CCAP), developed by the Clinton Administration in 1993 to stabilize U.S. greenhouse gas emissions by 2000 at 1990 levels. Carbon emissions from fuel combustion, the primary source of greenhouse gas emissions, were about 1,345 million metric tons in 1990. The analysis does not account for carbon-absorbing sinks, the 13 CCAP actions related to non-energy programs or gases other than carbon dioxide, nor any future mitigation actions that may be considered to meet the reductions proposed in the Kyoto Protocol.

Emissions in the 1990s have grown more rapidly than projected at the time CCAP was formulated, partly due to lower energy prices and higher economic growth than projected, which have led to higher energy demand. In addition, some CCAP programs have been curtailed.

Carbon Emissions From the Transportation Sector Grow Rapidly

Figure 121. Carbon emissions per capita, 1990-2020 (metric tons per person)



U.S. carbon emissions from energy use are projected to grow at an average annual rate of 1.3 percent; however, per capita emissions grow by only 0.5 percent a year (Figure 121). To stabilize or reduce total emissions, population growth would need to be offset by reductions in per capita emissions.

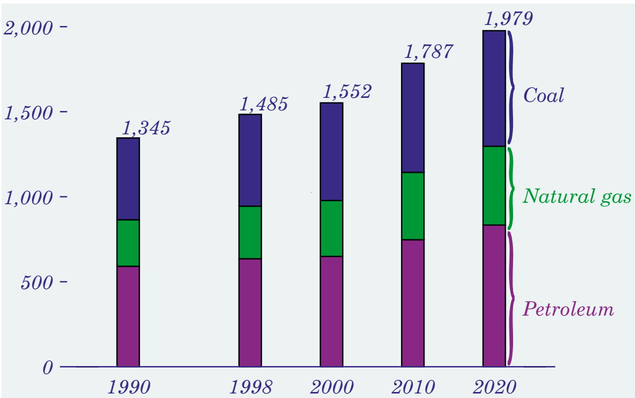
Emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.3 percent a year, reflecting the ongoing trends of electrification and penetration of new appliances and services. Significant growth in office equipment and other uses is also projected in the commercial sector, but growth in consumption—and in emissions, which increase by 1.2 percent a year—is likely to be moderated by slowing growth in floorspace.

Transportation emissions grow at an average annual rate of 1.7 percent as a result of increases in vehicle-miles traveled and freight and air travel, combined with stable average light-duty fleet efficiency. Industrial emissions are projected to grow by only 0.9 percent a year, as shifts to less energy-intensive industries and efficiency gains moderate growth in energy use.

In all sectors, potential growth in carbon emissions is moderated by efficiency standards, voluntary efficiency programs, and improvements in technology. Carbon mitigation programs in addition to CCAP, further improvements in technology, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

Petroleum Products Lead Carbon Emissions From Energy Use

Figure 122. Carbon emissions by fuel, 1990-2020 (million metric tons)



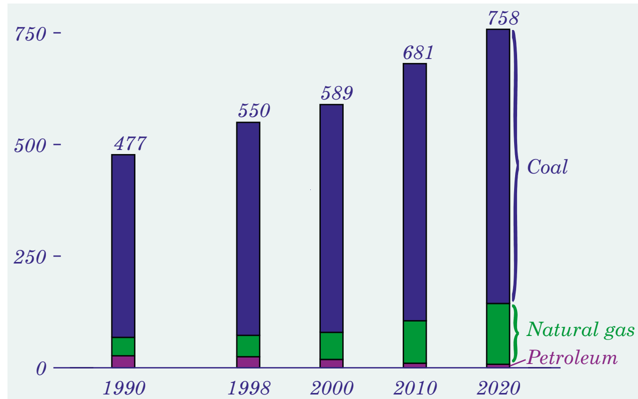
Petroleum products are the leading source of carbon emissions from energy use. In 2020, petroleum is projected to contribute 833 million metric tons of carbon to the total 1,979 million metric tons, a 42-percent share (Figure 122). About 82 percent (680 million metric tons) of the petroleum emissions result from transportation use, which could be lower with less travel or more rapid development and adoption of higher efficiency or alternative-fuel vehicles.

Coal is the second leading source of carbon emissions, projected to produce 680 million metric tons in 2020, or 34 percent of the total. The share declines from 36 percent in 1998 because coal consumption increases at a slower rate through 2020 than consumption of petroleum and natural gas, the sources of virtually all other energy-related carbon emissions. Most of the increases in coal emissions result from electricity generation. In the industrial sector, there is a slight increase in emissions from steam coal use and a slight decline in emissions from coking coal.

In 2020, natural gas use is projected to produce 464 million metric tons of carbon emissions, a 23-percent share. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2020, at an average annual rate of 1.8 percent; however, natural gas produces only half the carbon emissions of coal per unit of input. Average emissions from petroleum use are between those for coal and natural gas. The use of renewable fuels and nuclear generation, which emit little or no carbon, mitigates the growth of emissions.

Electricity Use Is Another Major Cause of Carbon Emissions

Figure 123. Carbon emissions from electricity generation by fuel, 1990-2020 (million metric tons)



Electricity generation is a major cause of carbon emissions. Although electricity produces no emissions at the point of use, generation accounted for 37 percent of total carbon emissions in 1998, and its share is expected to increase to 38 percent in 2020. Coal accounts for about 52 percent of electricity generation in 2020 (excluding cogeneration) and produces 81 percent of electricity-related carbon emissions (Figure 123). In 2020, natural gas accounts for 28 percent of electricity generation but only 18 percent of electricity-related carbon emissions.

Between 1998 and 2020, 40 gigawatts of nuclear capacity are expected to be retired, resulting in a 37-percent decline in nuclear generation. To compensate for the loss of nuclear capacity and meet rising demand, 290 gigawatts of new fossil-fueled capacity (excluding cogeneration) will be needed. Increased generation from fossil fuels will raise electricity-related carbon emissions by 208 million metric tons, or 38 percent, from 1998 levels. Generation from renewable technologies, excluding cogenerators, increases by 33 billion kilowatthours, or 9 percent, between 1998 and 2020 but is insufficient to offset the projected increase in generation from fossil fuels.

The projections include announced activities under the Climate Challenge program, such as fuel switching, repowering, life extension, and demand-side management, but they do not include offset activities, such as reforestation. Additional use of lower carbon fuels, reduced electricity demand growth, and improved technologies all could contribute to lower emissions than are projected here.

Scrubber Retrofits Will Be Needed To Meet Sulfur Emissions Caps

Figure 124. Sulfur dioxide emissions from electricity generation, 1990-2020 (million tons)

CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to approximately 12 million tons in 1996, 9.48 million tons between 2000 and 2009, and 8.95 million tons a year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million tons per year may not be reached until after 2010. More than 95 percent of the SO_2 produced by generators results from coal combustion and the rest from residual oil.

CAAA90 called for the reductions to occur in two phases, with larger (more than 100 megawatts) and higher emitting (more than 2.5 pounds per million Btu) plants making reductions first. In Phase 1, 261 generating units at 110 plants were issued tradable emissions allowances permitting SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances may also be banked for use in future years. Switching to lower sulfur subbituminous coal was the option chosen by more than half the generators.

In Phase 2, beginning in 2000, emissions constraints on Phase 1 plants will be tightened, and limits will be set for the remaining 2,500 boilers at 1,000 plants. With allowance banking, emissions are expected to decline from 11.9 million tons in 1995 to 11.6 million in 2000 (Figure 124). When the SO_2 emissions cap tightens in 2000 and after, the price of allowances is expected to rise, reaching $233 per ton by 2005. As the price rises, it is expected that 21 gigawatts of capacity—about 70 300-megawatt plants—will be retrofitted with scrubbers to meet the Phase 2 goal.

A Significant Drop in Nitrogen Oxide Emissions Is Expected in 2000

Figure 125. Nitrogen oxide emissions from electricity generation, 1995-2020 (million tons)

Nitrogen oxide (NO_x) emissions from electricity generation in the United States will fall significantly over the next 5 years as new legislation takes effect (Figure 125). The reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with volatile organic compounds and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months. The CAAA90 NO_x reduction program calls for reductions at electric power plants in two phases, the first in 1995 and the second in 2000. The second phase of CAAA90 is expected to result in NO_x reductions of 0.8 million tons between 1999 and 2000.

Even after the CAAA90 regulations take effect, further effort may be needed in some areas. For several years the EPA and the States have studied the movement of ozone from State to State. The States in the Northeast have argued that emissions from coal plants in the Midwest make it difficult for them to meet national air quality standards for ground-level ozone, and they have petitioned the EPA to force the coal plant operators to reduce their emissions more than required under current rules.

The interpretation of ozone transport studies has been controversial. In September 1998 the EPA issued a rule, referred to as the ozone transport rule (OTR), to address the problem. The OTR calls for capping NO_x emissions in 22 midwestern and eastern States during the 5-month summer beginning in 2003. The OTR is currently being challenged in court, however, and its implementation has been stayed.